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PRESENT LAW AND PROPOSALS RELATING TO INCREASING DOMESTIC ENERGY PRODUCTION AND RESERVES

SCHEDULED FOR A HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND AGRICULTURAL TAXATION

OF THE

COMMITTEE ON FINANCE

ON JULY 27, 1990

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INTRODUCTION

This pamphlet,[1] prepared by the staff of the Joint Committee on Taxation, provides a discussion of various current and proposed tax provisions intended to increase U.S. energy production and reserves. The Senate Finance Subcommittee on Energy and Agricultural Taxation has scheduled a public hearing on that subject on July 27, 1990.

The first part of the pamphlet is an overview of tax provisions relating to the energy industry and a summary of the relevant proposals which are being considered. The second part is a description of specific tax provisions and proposals relating to energy production and reserves, including present law, the Administration budget proposals, Senate legislative proposals, and analysis of related issues.

[1] This pamphlet may be cited as follows: Joint Committee on Taxation, *Present Law and Proposals Relating to Increasing Domestic Energy Production and Reserves* (JCS-23-90), July 26, 1990.

I. OVERVIEW AND SUMMARY

A. Energy Tax Provisions in General

A significant portion of the nation's energy policy is located in the Internal Revenue Code rather than in Federal outlay and regulatory programs. Tax expenditures for energy in the Code, in the form of credits and other tax preferences, are estimated to be approximately $1 billion in fiscal year 1991, and are estimated to be approximately $7.5 billion over the five-year period of 1991 through 1995.[2] These figures compare to the total amount of budget authority for energy programs ($3.2 billion) requested by the Administration in the fiscal year 1991 budget.[3]

The Code contains provisions that influence both energy supply and energy conservation. The most significant of the energy supply provisions from the standpoint of tax revenue involve the deduction of expenses associated with the exploration, development, and depletion of fossil fuels (primarily oil, natural gas, and coal). These provisions became part of U.S. tax law soon after the adoption of the income tax.

Following the 1973 oil embargo, and the economic disruption associated with the subsequent quadrupling of the world price of oil, Congress enacted several tax credits in the Energy Tax Act of 1978 that were explicitly designed to reduce U.S. dependence on energy imports. These energy tax credits were designed to encourage private expenditures for energy conservation, investment in facilities for producing energy from renewable fuel sources, and for the production of nonconventional energy.[4] Since 1978, many of the energy credits enacted by Congress have been narrowed, repealed, or allowed to expire.

Following the Tax Reform Act of 1986 (the "1986 Act"), the only business energy tax credits that remained in effect were credits for certain investments in solar energy property, geothermal energy property, ocean thermal property, and biomass energy property. Although retained in the tax law, the 1986 Act reduced the credit percentage for most of these credits, and provided for the expira-

[2] The figures are the arithmetic sum of individual tax expenditure items related to energy production as detailed in Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 1991-1995* (JCS-7-90), March 9, 1990. Each tax expenditure is measured in isolation and changes in more than one tax expenditure provision would be expected to produce interaction effects not captured in the sum of the individual tax expenditure items. Therefore, these estimates should be interpreted with caution. They are presented merely to provide information as to the magnitudes of tax subsidies for energy production relative to a truly comprehensive income tax system.

[3] This figure is the total for Budget Category 270, Energy, as reported in Office of Management and Budget, *Budget of the United States Government Fiscal Year 1991*, February 1990, p. A-146.

[4] In addition, the Crude Oil and Windfall Profits Tax Act of 1980 provided for the expensing of injectants used in tertiary oil recovery and allowed tax-exempt industrial development bonds to be used to finance certain alternative energy facilities.

tion of each of the credits by or before the end of 1988. The Technical and Miscellaneous Revenue Act of 1988 (the "1988 Act") extended for one year (through 1989) the credits for solar energy, geothermal energy, and ocean thermal property. The Omnibus Budget Reconciliation Act of 1989 (the "1989 Act") included an additional nine-month extension of these three credits (through September 30, 1990).

A production credit equal to $3 per BTU equivalent of a barrel of oil (adjusted for inflation) is allowed for producers of nonconventional fuels. Qualified nonconventional fuels include oil produced from shale or tar sands; certain gas produced from geopressurized brine, Devonian shale, coal seams, a tight formation, or biomass; and synthetic fuels produced from coal (including lignite).

Blends of ethanol (from renewable sources) and gasoline ("gasohol") are exempt from a portion of the Federal motor fuels excise tax. This provision was first contained in the Energy Tax Act of 1978 and the exemption was increased in the Deficit Reduction Act of 1984 to 6 cents of the 9 cents per gallon Federal motor fuels excise tax. In addition, the Crude Oil Windfall Profits Tax Act of 1980 provided a credit of 40 cents per gallon for renewably derived ethanol used to produce a mixture of ethanol and gasoline. This credit was increased to 60 cents per gallon by the Deficit Reduction Act of 1984.

Several of the energy incentives contained in the Code are scheduled to expire in the near future. As noted above, each of the remaining business energy credits is scheduled to expire after September 30, 1990. The credit for producing fuel from a nonconventional source is applicable only for qualified fuels that are produced from a well drilled (or from a facility placed in service) before January 1, 1991, and which are sold before January 1, 2001. In addition, the alcohol fuels credit is scheduled to terminate with respect to any sale or use of such fuel after December 31, 1992.

U.S. policy has directly affected energy prices and production through non-tax means. For instance, Congress provided for the deregulation of natural gas prices in the Natural Gas Policy Act of 1978 and in the Natural Gas Wellhead Decontrol Act of 1989, and the Administration decontrolled petroleum prices between 1979 and 1981. As a result, domestic petroleum and natural gas prices are now at or near world market levels.

Primarily as a result of energy price increases and conservation measures, aggregate U.S. petroleum consumption decreased by over 10 percent from 1978 to 1989. During the same period, U.S. petroleum consumption per dollar of GNP decreased over 30 percent. Again using the same reference period, U.S. petroleum production (including natural gas plant liquids) decreased by approximately 10 percent.[5] The declines in both consumption and production have resulted in a reduction in net imports of crude oil and refined products of 11 percent from 1978 to 1989. However, over the 1978-1989 period, net petroleum imports first declined and then increased as a percentage of domestic supply. A recent rise in imports of oil has brought the U.S. dependence on imported oil to approximately the

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[5] Figures calculated from U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), pp. 11, 115, 293.

same level it was in 1978 (41.3 percent for 1989 compared to 42.5 percent in 1978). In 1989, the Organization of Petroleum Exporting Countries ("OPEC") supplied 23.8 percent, and Arab members of OPEC supplied 12.3 percent, of U.S. petroleum demand.[6]

U.S. vulnerability to petroleum supply disruptions to some extent has been addressed by the establishment of a Federal strategic petroleum reserve ("SPR"). The SPR contains 580 million barrels of oil (as of year end 1989), capable of replacing 81 days of net oil imports at 1989 import rates (7.1 million barrels per day). Since 1985, the level of security provided by the SPR has declined yearly from 115 days of net oil imports in 1985 to 81 days of net oil imports in 1989. This decline reflects primarily the increased use of imported oil in the U.S., since the SPR has grown by approximately 86 million barrels over the period.

Each year from 1971 to 1982, the proved oil and gas reserves of the U.S. declined, meaning production outstripped net additions to reserves. However, the period 1982–1985 shows a rough equivalence between production and additions to proved reserves. Since 1986, though, annual domestic production of oil and gas has tended to be somewhat larger than additions to proved reserves (data for 1988 shows a slight reversal of this trend, with additions to proved reserves higher than production for that year). The decline in proved reserves of oil and gas can be partially attributed to a decline in exploration and development activity. For example, the total number of wells completed has declined from an annual average of over 80,000 wells for the 1982–1984 period to an annual average of 31,500 wells for 1987–1989.[7]

In evaluating the provisions of the Code affecting energy production and use, and proposed changes to these provisions, several important issues arise. First, the role of the U.S. Government needs to be addressed. For instance, a prominent question is whether the Federal Government, in view of national policy considerations, should attempt to influence the level and composition of private energy supply and demand, or whether it should let free-market prices determine these decisions. Second, the efficiency of using the tax system to affect energy production and utilization should be examined. Even if national energy policy seeks to encourage certain energy production and conservation activities, one needs to consider whether it is more efficient to use direct outlay programs or tax incentives to influence the use or production of energy. Third, the efficiency of present Code provisions should be analyzed to determine whether these provisions can be made more efficient. Fourth, the redistributional role of energy-related tax provisions should be weighed to determine the extent to which these provisions affect the distribution of income among individual taxpayers and between regions of the country.

B. Administration Proposals

President Bush's Fiscal Year 1991 Budget includes several proposed tax incentives for the domestic oil and gas industry. These

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[6] U.S. Department of Energy, *Monthly Energy Review: February 1990* (May 1990), p. 13.
[7] U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), pp. 97, 101, 103, 143.

proposals include: (1) a 5- and 10-percent tax credit for intangible drilling costs ("IDCs") attributable to exploratory drilling; (2) a 10-percent tax credit for capital expenditures on tertiary enhanced recovery projects; (3) increasing the net income limitation on percentage depletion from 50 to 100 percent of net income from the property; (4) allowing transferred proven property to qualify for percentage depletion; and (5) elimination of 80 percent of the minimum tax preference for intangible drilling costs attributable to exploratory drilling by independent producers. These proposals would be effective on January 1, 1991.

C. Senate Legislative Proposals

1. S. 41—Senator Nickles (Energy Security Act of 1989)

S. 41 would provide certain income tax incentives for domestic oil and gas production. The bill would allow percentage depletion at a 27.5-percent rate for domestic new, enhanced, and stripper production (from property held by an independent producer or royalty owner), increase the net income limitation on percentage depletion from 50 to 100 percent, increase the taxable income limitation on percentage depletion from 65 to 100 percent, and allow transferred proven properties to qualify for percentage depletion.

The bill also would treat geological and geophysical ("G&G") costs as expensible similar to the present-law treatment of IDCs, and would exclude IDCs from the list of preference items for purposes of the alternative minimum tax. The bill would provide a 5- and 10-percent crude oil and natural gas exploration and development tax credit. Further, the bill would apply a 3-year statute of limitations on crude oil windfall profit tax assessments in certain cases of underwithholding of tax where the producer did not file a required tax return.

The provisions generally would become effective on the date of enactment.

2. S. 42—Senator Nickles (Domestic Petroleum Security Act of 1989)

S. 42 would impose an excise tax on crude oil or any other refined petroleum product that is imported into the United States. With respect to crude oil, the rate of the tax would be the excess (if any) of $18 over the price per barrel as established by the Secretary of the Treasury.[8] For other refined petroleum products, the excise tax rate would be equal to $3 plus the tax rate determined for crude oil. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export.

The bill would be effective with respect to sales or use of imported crude oil or refined petroleum products on or after date of enactment.

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[8] This price, which is to be determined on a weekly basis under the bill, is the weighted average international price of a barrel of crude oil for the preceding four weeks.

3. S. 161—Senators Boren and Kassebaum

S. 161 would impose an excise tax on any petroleum product that is imported into the United States if the average international price of crude oil for any 4-week period is less than $18, and the product is entered into the United States for use, consumption, or warehousing during the week following such 4-week period. The rate of the tax would be the excess of $18 over the average international price per barrel of crude oil for the preceding 4-week period. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export.

The bill would be effective with respect to sales of imported petroleum products in calendar quarters beginning more than 30 days after date of enactment.

4. S. 234—Senator Boren (Energy Security Incentive Act of 1989)

S. 234 would provide certain income tax incentives for domestic oil and gas production. Among these, the bill would increase the percentage depletion rate if the taxpayer's average removal price for crude oil is less than $20 per barrel, repeal the 50 percent of net income limitation and 65 percent of taxable income limitation on percentage depletion, allow transferred proven properties to qualify for percentage depletion, and provide for a carryover of depletion deductions in excess of basis.

In addition, the bill would eliminate the minimum tax preference for IDCs, eliminate the requirement that integrated oil companies capitalize 30 percent of their IDCs, eliminate recapture of IDCs and depletion upon disposition of an oil, gas or geothermal property, and treat G&G costs and surface casing costs as expensible in a manner similar to the treatment presently provided for IDCs.

The bill also would provide a 10-percent tax credit for maintaining economically marginal wells, and provide a 10- and 20-percent tax credit for crude oil and natural gas exploration and development costs. Further, the bill would extend the credit for producing fuel from nonconventional sources for five years (until 1996), and expand it to cover certain tight sands gas.

The provisions generally would be effective on the date of enactment.

5. S. 343—Senators Bingaman and Boren

S. 343 would extend the placed in service expiration date for the nonconventional fuels credit for 10 years. Thus, the credit would apply with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 2001. In addition, the bill would extend for 10 years the expiration date of the nonconventional fuels credit for sales of qualified fuels. Under the bill, the credit would apply to sales of qualified fuels occurring before January 1, 2011.

The bill also generally would extend the credit to all gas produced from a tight formation.

6. S. 425—Senator Domenici (Tight Formations Tax Credit Restoration Act of 1989)

S. 425 generally would treat gas produced from a tight formation as qualifying for the nonconventional fuels production credit. This provision would be effective for taxable years beginning after December 31, 1984.[9] The bill also would permit the credit to offset both the regular tax and the alternative minimum tax. This section of the bill would be effective for taxable years beginning after December 31, 1986.

7. S. 449—Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson (Domestic Energy Security Act of 1989)

S. 449 includes various energy tax incentive provisions, including provisions that would permit the expensing of G&G costs attributable to domestic oil and gas property, and allow for early accrual of expenses related to the removal of offshore oil and gas production facilities if a liability for such removal is included in the terms of an offshore oil or gas lease. The bill also contains a number of provisions that would amend the percentage depletion rules. For example, the bill would increase the 50-percent net income limitation to 100 percent, repeal the 65-percent taxable income limitation, and repeal the limitation on claiming percentage depletion on transferred proven oil and gas property.

The bill would repeal the requirement that integrated oil companies capitalize 30 percent of their otherwise deductible IDCs. With respect to the alternative minimum tax, the bill would eliminate the tax preference items related to IDCs and excess percentage depletion.

The bill also would provide for a 20-percent domestic exploration and development tax credit and a 20-percent tertiary recovery tax credit. Each of these credits would be permitted to fully offset both the regular tax and the alternative minimum tax. In addition, the bill would extend the expiration date of the nonconventional fuels production credit to December 31, 1998, and would make certain tight sands gas eligible for that credit.

Further, the bill contains provisions that would exclude oil and gas exploration and development costs from the uniform capitalization rules, and would repeal the treatment prescribed in Revenue Ruling 77-176 with respect to certain mineral sharing arrangements.

The provisions generally would be effective as of the date of enactment.

8. S. 828—Senators Domenici, Boren, Dole, Nickles, Garn, Wallop, Bingaman, Johnston, McClure, and Gramm (Enhanced Oil and Gas Recovery Tax Act of 1989)

S. 828 would increase the percentage depletion rate for domestic oil and gas recovered through enhanced recovery techniques to 27.5 percent, phased down as the price of crude oil increases above $30

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[9] If on the date of enactment any refund or credit of tax resulting from this legislation would be barred by the statute of limitations, such refund or credit would, nevertheless, be made or allowed if a claim is filed within one year of the date of enactment.

per barrel adjusted for inflation. The bill also would increase the net income limitation on percentage depletion of this oil and gas to 100 percent. The alternative minimum tax preferences for percentage depletion and intangible drilling costs would not apply to the deductions attributable to this oil and gas. Further, a 10-percent research and development credit would apply to research to discover or improve tertiary recovery methods.

The provisions generally would be effective beginning on the date of enactment and would expire on January 1, 2010.

9. S. 850—Senators Johnston and Bingaman (Energy Security Tax Act)

S. 850 would impose an excise tax on any crude oil, refined petroleum product, or petrochemical feedstock or derivative that is imported into the United States. With respect to crude oil, the rate of the tax would be the excess (if any) of $24 per barrel over the most recently published average price per barrel of internationally traded oil. For refined petroleum products and petrochemical feedstocks or derivatives, the excise tax rate would be equal to the excess (if any) of $26.50 per barrel (or barrel equivalent) over the most recently published average price per barrel of internationally traded oil. The bill would be effective with respect to sales or use of imported crude oil, refined petroleum products, or petrochemical feedstocks or derivatives on or after the date of enactment.

10. S. 914—Senator Matsunaga

S. 914 would extend through December 31, 1994, the current business energy credits for solar energy property, geothermal property, and ocean thermal property.

11. S. 1565—Senators Dole, Domenici, Boren, Nickles, Wallop, Gramm, and Baucus (Marginal Energy Producers Incentives Act of 1989)

S. 1565 contains five provisions, three of which are applicable only to "marginal" oil and gas production. For this purpose, marginal production includes production from stripper wells and production of heavy oil.

Under the bill, the limitation on claiming percentage depletion on transferred proven properties would be repealed, and the 50-percent net income limitation on percentage depletion would be changed to a 100-percent limitation. With respect only to marginal production, the bill would permit percentage depletion to be claimed by independent producers and royalty owners without taking into account the 1,000 barrel-per-day limitation. In addition, percentage depletion with respect to such production would not be subject to the 65-percent taxable income limitation. Further, excess percentage depletion on marginal properties would not constitute an item of tax preference for the alternative minimum tax.

The bill's provisions would be effective for taxable years ending after date of enactment.

12. S. 2025—Senators Heinz, Moynihan, Durenberger, Danforth, Symms, Boren, Levin, McCain, Cochran, Burns, Akaka, Cohen, and Hollings

S. 2025 would provide for the permanent extension of various tax provisions that are currently scheduled to expire. Among these, the bill would extend permanently the current business energy credits for ocean thermal property, solar energy property, and geothermal property. In addition, the bill would provide for the permanent extension of the nonconventional fuels production credit.

13. S. 2288—Senators Domenici, Boren, Johnston, Dole, Bingaman, Ford, Simpson, Wallop, and Burns (Nonconventional Fuels Production Incentives Act of 1990)

S. 2288 would extend the nonconventional fuels production credit by two years, making it applicable with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 1993. In addition, the bill would extend the credit to the production of gas from a tight formation if that gas is (1) produced from a well drilled after May 12, 1990, or (2) produced from a well drilled before May 12, 1990, but only if on that date gas produced from that well was gas that was regulated by the United States as to its price, and for which the maximum lawful price applicable under the Natural Gas Policy Act of 1978 is at least 150 percent of the then applicable price under section 103 of that Act. This latter provision would apply to gas produced after May 12, 1990.

II. DESCRIPTION OF TAX PROVISIONS AND PROPOSALS

A. Tax Provisions Relating To Oil And Gas Production

1. Intangible Drilling and Development Costs

Present Law and Background

General rules

Costs incurred by an operator to develop an oil or gas property for production are of two types: (1) intangible drilling and development costs ("IDCs"), and (2) depreciable costs.

Under present law, IDCs generally may either be currently expensed or else may be capitalized and recovered through depletion or depreciation deductions (as appropriate), at the election of the operator (Code sec. 263(c)).[10] In general, IDCs include expenditures by the property operator incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas (or geothermal energy) which are neither for the purchase of tangible property nor part of the acquisition price of an interest in the property.[11] IDCs include amounts paid for labor, fuel, repairs, hauling, supplies, etc., to clear and drain the well site, make an access road, and do such survey and geological work as is necessary to prepare for actual drilling. They also include charges for labor, etc., necessary to construct derricks, tanks, pipelines, and other physical structures necessary to drill the wells and prepare them for production. IDCs may include amounts paid or accrued to drill, shoot, and clean the wells. IDCs also include amounts paid or accrued by the property operator for drilling or development work done by contractors under any form of contract.

Depreciable costs are amounts paid or accrued during the development of a property to acquire tangible property ordinarily considered to have a salvage value. For example, the costs of drilling tools, pipe, cases, tubing, engines, boilers, machines, etc., fall into this category. This class of expenditures also includes certain amounts paid or accrued for wages, fuel, repairs, etc., in connection with equipment or facilities not incidental or necessary for the drilling of wells, such as structures to store or treat oil or natural gas. These expenditures must be capitalized and depreciated in the same manner as ordinary items of equipment, and they are treated the same for both independent and integrated producers.

Only persons holding an operating interest in a property are entitled to deduct IDCs. This includes an operating or working interest in any tract or parcel of oil- or gas-producing land either as a

[10] As discussed more fully below, a third alternative permits taxpayers to elect to amortize certain IDCs over a 60-month period.

[11] The acquisition price for the actual oil- or gas-producing property, together with certain other costs, is recovered through depletion deductions (see discussion of depletion below).

fee owner, or under a lease or any other form of contract granting working or operating rights. In general, the operating interest in an oil or gas property must bear the cost of developing and operating the property. The term operating interest does not include royalty interests or similar interests such as production payment rights or net profits interests.

In the case of IDCs paid or incurred with respect to an oil, gas, or geothermal well located outside of the United States, the option to expense such costs is not available. Instead, such costs are (at the election of the taxpayer) either included in the property's basis for purposes of claiming depletion, or capitalized and amortized ratably over the 10-taxable year period beginning with the taxable year during which the costs were paid or incurred.

Generally, if IDCs are not expensed, but are capitalized, they can be recovered through depletion or depreciation, as appropriate. However, if IDCs are capitalized and are paid or incurred with respect to a nonproductive well ("dry hole"), they may be deducted, at the election of the operator, as an ordinary loss in the taxable year in which the dry hole is completed. Thus, a taxpayer has the option of capitalizing IDCs for productive wells while expensing those relating to dry holes.

Thirty percent reduction for integrated producers

In the case of a corporation which is not an independent producer [12] (i.e., which is an "integrated" producer), the allowable deduction with respect to IDCs is reduced by 30 percent. The disallowed amount must be capitalized and amortized over a 60-month period, starting with the month in which the costs are paid or accrued. (These capitalized IDCs are not taken into account for purposes of determining cost depletion.) Amounts paid or accrued with respect to non-productive wells (dry hole costs) remain fully deductible when the non-productive well is completed.

Recapture of IDCs

If an operator elects to expense IDCs and later disposes of an oil, gas, or geothermal property, a portion of the gain recognized (if any) as a result of the disposition of that property must be characterized as ordinary income (instead of capital gain) (sec. 1254(a)). The portion so characterized is equal to the lesser of (1) the amount of IDCs deducted with respect to that property which, but for being deducted, would have been reflected in the adjusted basis of the property plus the deductions for depletion which reduced the adjusted basis of that property, or (2) the gain on the sale, exchange, or involuntary conversion of the property.[13]

Alternative minimum tax

While IDCs are currently deductible (at the election of the operator), the economic value of this current deduction may be reduced by the effect of the alternative minimum tax with respect to both

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[12] This term is defined in the same manner as it is for purposes of percentage depletion (discussed below).

[13] Even if the taxpayer did not elect to expense IDCs, ordinary income recapture of depletion deductions with respect to the property disposed of would be required.

corporate and noncorporate operators. In the case of an individual, trust, or estate (i.e., a noncorporate taxpayer), the alternative minimum tax is equal to 21 percent of the excess of the taxpayer's alternative minimum taxable income over a statutory exemption amount, reduced by the alternative minimum tax foreign tax credit. In the case of a corporate taxpayer, the alternative minimum tax is equal to 20 percent of such excess.[14] Alternative minimum taxable income is taxable income, determined with respect to certain adjustments (as specified in secs. 56 and 58), plus the amount of the taxpayer's tax preference items (as specified in sec. 57).

In general, IDC deductions on successful wells are a tax preference item for purposes of the alternative minimum tax to the extent they exceed the amount which would have been deductible in that year had the IDCs been capitalized and recovered over a 120-month, straight-line amortization period (i.e., "excess IDCs"), but only to the extent that the excess IDCs are greater than 65 percent of the taxpayer's income for the taxable year from the oil or gas property (sec. 57(a)(2)). The 120-month amortization period applies on a well by well basis, starting with the month in which production for the well begins. At the election of the operator, the cost depletion method may be substituted for the 120-month amortization in determining the amount of tax preference. Generally, a minimum tax credit is allowed in succeeding years for minimum tax paid by reason of the preference for IDCs.

In the case of corporations, one adjustment that is required in arriving at alternative minimum taxable income is an adjustment based on adjusted current earnings (the "ACE adjustment") (sec. 56(g)). Under the ACE adjustment, a corporation's alternative minimum taxable income for a taxable year is increased by 75 percent of the excess (if any) of the corporation's adjusted current earnings computed in a manner similar to earnings and profits, over its alternative minimum taxable income (determined without regard to the ACE adjustment or any net operating loss deduction). For the purpose of determining adjusted current earnings, IDCs deducted for regular tax purposes are required to be capitalized and amortized over a 60-month period beginning with the month during which the IDC was paid or incurred.

Under a special rule provided in section 59(e), a taxpayer is permitted to elect to capitalize any amount of otherwise deductible IDCs and amortize that amount over a 60-month period beginning with the month in which the IDC was paid or incurred. Prior to the 1989 Act, the amortization period for IDCs with respect to which this special election was made was 120 months, beginning with the taxable year in which the IDC was paid or incurred. This special rule is applicable for both regular tax and alternative minimum tax purposes.

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[14] The exemption amount generally is equal to $30,000 for single individuals, $40,000 for corporations, married couples filing joint returns, or surviving spouses, and $20,000 for married persons filing separate returns or for estates or trusts (sec. 55(d)). These exemption amounts, however, are phased out for certain high-income taxpayers.

Administration Proposal

The Administration proposal would eliminate 80 percent of the current alternative minimum tax preference generated by exploratory IDCs incurred by an independent producer.[15] The proposal would be effective on January 1, 1991.

Other Proposals

S. 41 (Senator Nickles)

S. 41 would repeal the treatment of excess IDCs as a minimum tax preference item, effective for costs paid or incurred after the date of enactment.

S. 234 (Senator Boren)

S. 234 would repeal the rules providing for recapture of intangible drilling cost deductions and depletion deductions upon disposition of an oil, gas or geothermal property. This provision would be effective for dispositions of oil, gas, or geothermal properties after the date of enactment.

The bill also would repeal the treatment of excess IDCs as a minimum tax preference. In addition, the bill would repeal the present-law requirement that integrated oil companies capitalize 30 percent of their IDCs. These proposals would be effective for costs paid or incurred after date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would repeal the treatment of excess IDCs as a minimum tax preference. The bill also would repeal the present-law requirement that integrated oil companies capitalize 30 percent of their IDCs. These proposals would be effective for costs paid or incurred after date of enactment.

S. 828 (Senators Domenici, Boren, Dole, Nickles, Wallop, Garn, Bingaman, Johnston, McClure, and Gramm)

S. 828 would repeal the treatment of excess IDCs as a minimum tax preference for oil and gas removed through enhanced recovery techniques if the removal price of oil is less than $30 per barrel adjusted for inflation.[16] This provision would be effective for costs paid or incurred after date of enactment, and before January 1, 2010 (with respect to projects beginning before January 1, 2000).

Analysis

In general

When considering whether energy incentives should be included as part of the tax law, one issue to be considered is whether investments in oil and gas should be given preferential treatment relative to other capital investments. The Administration contends that preferential treatment of IDCs is necessary to increase the

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[15] The Administration proposal does not discuss the treatment of IDCs under the present-law ACE adjustment.

[16] See discussion of oil and gas recovered through enhanced recovery techniques below.

level of domestic exploratory drilling (and ultimately domestic oil and gas reserves), thus reducing the United States' dependence on foreign oil supplies and improving U.S. energy security.

Evidence that domestic drilling activity has fallen over recent years is dramatic. According to Department of Energy statistics, the number of exploratory and development oil and gas wells drilled in 1989 (28,470) was smaller than the number drilled in any year since 1973 (when the number of wells drilled was 27,690).[17] The number of seismic crews and rotary rigs in use has also decreased significantly in recent years. Both the number of seismic crews and the number of rotary rigs in operation were smaller in 1989 than in any year since 1949. Part of this may reflect increased productivity on the part of drilling firms (in that fewer crews are needed to drill the same number of wells). However, a large portion of the decline reflects decreased domestic drilling activity.

The various proposals are premised on the contention that providing tax incentives for drilling activity is necessary to increase U.S. energy security. In 1989, the U.S. imported an average of 8.0 million barrels of oil per day, accounting for 41.3 percent of domestic petroleum supply. In the event of a complete curtailment of imports, the SPR could, at current levels, replace net imports for approximately 81 days. If the SPR were depleted, domestic production would have to nearly double to replace imports (assuming that domestic consumption does not decline). As of 1988, proved reserves of crude oil amounted to just 9.0 years of domestic production (at 1988 rate of 8.1 million barrels per day). If production rates were increased to replace all imports, proved reserves would be exhausted in less than 4.5 years.[17A] To respond to a future oil import curtailment, it is argued that proved reserves must be increased now because it can take several years from initial discovery for a petroleum reservoir to reach maximum production. It is argued that energy security would be increased by expanding tax preferences in current law for intangible drilling costs and percentage depletion. It is also argued that these tax incentives should be expanded in order to maintain adequate levels of labor and equipment in the oil and gas industry in the event of an energy crisis.

Some have questioned this view on the grounds that drilling incentives may lead to a substitution of domestic oil for imports—in effect "draining America first". They argue that domestic oil production is likely to rise along with reserve additions yielding little net increase in field reserves. Some argue that it may be more efficient to stockpile petroleum by filling the SPR with oil purchased in the world market at the currently prevailing prices than to provide additional incentives for domestic production.

Others argue that the object of energy policy should be complete energy independence. In this view, tax incentives for oil and gas exploration serve energy policy by increasing domestic production and replacing imports. These incentives might also improve the merchandise trade balance since net petroleum imports accounted

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[17] U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), p. 97 (excludes service well, stratigraphic tests, and core tests). The oil and gas well footage drilled in 1989 (130.9 million feet) was the smallest for any year since 1949 except for 1971 (when the footage drilled was 127.3 million feet).

[17A] U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), pp. 103, 115.

for over 10 percent of all imports in 1989.[18] However, enhanced energy self-sufficiency might be achieved more efficiently by a tax on imported oil. Such a tax, it is argued, would encourage conservation and fuel switching, as well as production, by raising the price of domestic oil. Opponents of an oil import fee might contend that the price increase of domestic oil would, in effect, be a wealth transfer to owners of oil reserves, since this would provide an unexpected boost to the market value of these reserves. In addition, an oil import fee might raise questions regarding U.S. trade policy in the context of the General Agreement on Tariffs and Trade (GATT).

From an accounting standpoint, part of the reason that IDCs have historically been allowed to be expensed [19] (aside from the implicit tax subsidy) is the difficulty of establishing an alternate recovery period, because the "useful life" of a well may not be known in advance and its production may occur at an uneven rate. (This is similar to the problem faced in determining a proper oil and gas depletion method.)

Recapture of IDCs

Gain from the sale of oil, gas, and geothermal property attributable to deductions for intangible drilling costs and depletion allowances are treated as ordinary income rather than capital gain. Since ordinary income and capital gains are taxed at the same rate, the effect of the recapture rule is to prevent recapture income from being sheltered by capital losses for taxpayers with net capital losses (or capital loss carryforwards). The recapture rules for oil and gas property are similar to the rules applicable to depreciable property. The relevant provision of S. 234 would afford oil and gas property more favorable recapture treatment than depreciable property—treatment that actually would be more beneficial to the taxpayer than the rules in existence before the 1986 Act.[20]

Alternative minimum tax

The alternative minimum tax, as amended by the 1986 Act, requires that taxpayers pay a minimum rate of tax (21 percent in the case of noncorporate taxpayers and 20 percent in the case of corporations) on a broad measure of their economic income. To the extent that taxable income is reduced by reason of the expensing of IDCs on successful wells, the 65-percent income offset contained in present law lowers the 20- and 21-percent effective rates of tax. Repeal of the tax preference for excess IDCs would allow some producers to further reduce (or eliminate) their effective rate of tax.

An argument in favor of such a proposal is that it would increase the tax incentive for incurring drilling expenses for producers that are subject to the alternative minimum tax. To the extent that repeal of the IDC preference allows producers to shelter most or all

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[18] U.S. Department of Energy, *Monthly Energy Review: February 1990* (May 1990), p. 11.

[19] The option to expense IDCs has been permitted by regulations since the Revenue Act of 1918. In 1945, in response to a case casting doubt on this treatment, Congress passed a concurrent resolution which specifically approved the Treasury regulations granting the option to expense IDCs. The Internal Revenue Code of 1954 (sec. 263(c)) directs the Treasury Department to promulgate regulations allowing for the option to expense IDCs.

[20] Prior to the 1986 Act, recapture generally was required only for IDCs.

of their income from tax, however, other taxpayers may view the tax law as inequitable. Also, allowing an exception to the alternative minimum tax for the oil and gas industry might be a precedent for other industries seeking exceptions from the minimum tax.

2. Percentage Depletion

Present Law and Background

General rules

Depletion, like depreciation, is a class of ordinary and necessary business expense. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset—in the case of depletion, the oil or gas reserve itself—is being expended in order to produce income. Certain costs incurred prior to drilling an oil- or gas-producing property are recovered through the depletion deduction. These include costs of acquiring the lease or other interest in the property, and geological and geophysical costs (in advance of actual drilling). Depletion is available to any person having an economic interest in a producing property (including royalty interests).

Two methods of depletion are currently allowable under the Internal Revenue Code: (1) the cost depletion method, and (2) the percentage depletion method. Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the taxable year (in general, the number of units remaining to be recovered in the property at the end of the taxable year, plus the number of units sold during the taxable year). The amount recovered under cost depletion thus may not exceed the taxpayer's basis in the property.

Under percentage depletion, 15 percent of the taxpayer's gross income from an oil- or gas-producing property is allowed as a deduction in each taxable year (sec. 613A(c)). The amount deducted may not exceed 50 percent of the net income from that property in any year (the "net income limitation"). Additionally, the deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).[21] Because percentage depletion is computed without regard to the taxpayer's basis in a property, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine its depletion deduction for each oil and gas property under both the percentage depletion method (if the taxpayer is entitled to use this method) and the cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question.

Similar rules apply to geothermal deposits located in the United States, except that the 65 percent of taxable income limitation does not apply.

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[21] Amounts disallowed as a result of this rule may be carried forward into later taxable years.

Limitation on percentage depletion or oil and gas to independent producers and royalty owners

The Tax Reduction Act of 1975 repealed percentage depletion with respect to much oil and gas production. Under that Act, independent producers and royalty owners (as contrasted to integrated oil companies) are allowed to claim percentage depletion with respect to up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas.[22] For producers of both oil and natural gas, this limitation applies on a combined basis.

For purposes of percentage depletion, an independent producer is any producer who is not a "retailer" or "refiner." A retailer is any person who directly, or through a related person, sells oil or natural gas or any product derived therefrom (1) through any retail outlet operated by the taxpayer or related person, or (2) to any person that is obligated to market or distribute such oil or natural gas (or product derived therefrom) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the taxpayer or a related person (sec. 613A(d)(2)). Bulk sales to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are excluded for this purpose. Further, a person is not a retailer within the meaning of this provision if the combined gross receipts of that person and all related persons from the retail sale of oil, natural gas, or any product derived therefrom do not exceed $5 million for the taxable year.

A refiner is any person who directly or through a related person engages in the refining of crude oil, but only if such taxpayer or related person has a refinery run in excess of 50,000 barrels per day on any day during the taxable year (sec. 613A(d)(4)).

In addition to the independent producer and royalty owner exception, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressurized brine,[23] are eligible for percentage depletion, at rates of 22 percent and 10 percent respectively. These exceptions apply without regard to the 1,000 barrel per day limitation and regardless of whether the producer is an independent producer or an integrated oil company.

To prevent proliferation of the independent producer exception, all production owned by businesses under common control and members of the same family must be aggregated. Each group is then treated as one producer for application of the 1,000-barrel amount. Further, if an interest in a proven oil or gas property is transferred (subject to certain exceptions), the production from such interest does not qualify for percentage depletion. The exceptions to this rule include transfers at death, certain transfers to controlled corporations, and transfers between controlled corporations or other business entities.

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[22] As originally enacted, the depletable oil quantity was 2,000 barrels of average daily production. This was gradually phased down to 1,000 barrels of average daily production for 1980 and thereafter. The 1975 Act also phased down the percentage depletion rate from 22 percent in 1975 to 15 percent in 1984 and thereafter.

[23] This exception is limited to wells the drilling of which began between September 30, 1978, and January 1, 1984.

Alternative minimum tax

The excess of percentage depletion over the taxpayer's adjusted basis for each oil or gas property, [24] for any taxable year, is treated as a preference item for purposes of the alternative minimum tax.[25]

Administration Proposal

The Administration proposal would increase the oil and gas percentage depletion net income limitation from 50 percent to 100 percent of net income from the property. In addition, the proposal would repeal the rule which prevents percentage depletion from being claimed on transferred proven properties. The proposals would be effective on January 1, 1991.

Other Proposals

S. 41 (Senator Nickles)

S. 41 would provide a 27.5-percent depletion rate with respect to a taxpayer's domestic new, enhanced, or stripper production, as defined under the bill. This deduction would be available to all taxpayers (including independent and integrated producers), for an unlimited amount of production. For purposes of the bill, new production would include production from any property that commences production after March 31, 1987. Enhanced production would include (1) the increase in average daily production for the taxable year over average daily production for the period January 1, 1987, through March 31, 1987, and (2) incremental tertiary oil as defined for prior law windfall profit tax purposes (sec. 4993(a)). Stripper production would include production from any stripper well property as defined in the June 1979 Department of Energy regulations. This provision would be effective for production during the taxpayer's first full taxable quarter following the date of enactment.

In addition, S. 41 would repeal the percentage depletion antitransfer provision, effective for transfers of property taking place after the date of enactment. It also would increase the net income limitation from 50 to 100 percent and increase the taxable income limitation from 65 percent to 100 percent, effective for production for taxable years beginning after the date of enactment.

S. 234 (Senator Boren)

S. 234 would increase the percentage depletion rate for crude oil and natural gas, if the taxpayer's average removal price for oil and gas sold during the calendar year is $20 per barrel or less. The amount of the increase would depend upon the average annual removal price, as shown in the following table:

[24] In general, the term "property", for depletion purposes, means each separate interest owned by the taxpayer in each separate tract or parcel of land. In the case of oil and gas wells and geothermal deposits, all of a taxpayer's operating interests in each separate tract or parcel of land are generally treated as one property, subject to an election to separate certain interests in the same tract or panel.

[25] For a more in depth discussion of the alternative minimum tax, see above.

*If the average annual removal price during the calendar year is:**	*The applicable percentage is:*
Less than $10	30 percent
$10 to $15	25 percent
$15 to $20	20 percent
Greater than $20	15 percent

*These prices are measured in dollars per barrel.

The "average annual removal price" for the taxpayer would be determined by dividing the taxpayer's aggregate production of domestic crude oil or natural gas for the calendar year by the aggregate amount for which such production was sold.[26] In the case of crude oil or natural gas sold between related persons, removed before sale, or refined on the production premises, a constructive sales price would be used. For example, if a taxpayer sold 100,000 barrels of crude oil for an aggregate price of $1.8 million in calendar year 1990, the taxpayer's average removal price would be $18 per barrel, and a percentage depletion rate of 20 percent would apply to all production by that taxpayer in 1990.

Percentage depletion would continue to be limited to 1,000 barrels per day of domestic crude oil production (or an equivalent amount of natural gas) by independent producers. Additionally, the limitation on percentage depletion deductions for all oil and gas properties to 65 percent of the taxpayer's overall taxable income would remain in effect.

The changes in the percentage depletion rate would be effective for production during calendar years beginning after date of enactment.

The bill also would repeal the percentage depletion anti-transfer provision, for production during calendar years beginning after date of enactment. In addition, it would repeal the 50-percent net income limitation on percentage depletion deductions for oil and gas properties. Thus, percentage depletion would equal the specified percentage of gross income from each property, without regard to the net income from that property. The overall limitation to 65 percent of adjusted taxable income would continue to apply. The repeal of the net income limitation would be effective for taxable years beginning after the date of enactment.

Finally, the bill would allow a taxpayer to elect to treat any amount of percentage depletion in excess of basis as a deduction for the next succeeding year rather than the current year.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would repeal the percentage depletion anti-transfer provision, for transfers occurring after date of enactment. It also would repeal the 50-percent net income limitation on percentage depletion deductions for oil and gas properties. The bill also would repeal the 65-percent taxable income limitation on oil and gas per-

[26] The bill apparently intends that the average annual removal price be determined by dividing removal production in barrel-of-oil equivalents into (rather than by) the amount for which such production was sold.

centage depletion. Thus, percentage depletion would equal the specified percentage of gross income from each property, without regard to either the net income from that property or the taxpayer's taxable income. These latter two provisions would apply to taxable years ending after date of enactment.

In addition, the bill would eliminate percentage depletion in excess of basis as an item of tax preference for the alternative minimum tax.

S. 828 (Senators Domenici, Boren, Dole, Nickles, Wallop, Garn, Bingaman, Johnston, McClure, and Gramm)

S. 828 would provide a 27.5-percent depletion rate with respect to the production of domestic incremental tertiary crude oil and gas during the enhanced recovery period. This deduction would be available to all taxpayers (including independent and integrated producers) for an unlimited amount of production. The 27.5-percent rate would be phased-down to 15 percent by one percentage point for every dollar that the taxpayer's average removal price of oil for the calendar year exceeds $30 dollars per barrel adjusted for post-1989 inflation.

For purposes of the bill, incremental tertiary oil and gas includes incremental tertiary oil as defined for prior law windfall profit tax purposes (sec. 4993(a) using the current Department of Energy (DOE) regulations). Tertiary recovery techniques, under DOE regulations, include miscible fluid displacement, steam driven injection, microemulsion or micellar emulsion flooding, in situ combustion, polymer augmented flooding, cyclic steam injection, alkaline or caustic flooding, carbon dioxide augmented water flooding, and immiscible carbon dioxide displacement. Reservoir improvements (including infill patterns and pattern conformance) incident to a qualified tertiary recovery project would be treated as a project which is otherwise a qualified tertiary project. Oil and gas produced from nonhydrocarbon gas flooding, tight formation gas, and certain tight formation oil would also qualify as incremental tertiary oil and gas under the bill.

The enhanced recovery period is a period, as determined by a schedule to be published by the Secretary of the Treasury, based on the average period for a project to recover the expenses of the type of project involved for that region. The recovery period would not end earlier than six months after the publication of the schedule by the Secretary.

The provision would be effective for production after the date of enactment and before January 1, 2010. It would apply after December 31, 1999, only to production from a project begun before January 1, 2000. Expansion of a project begun on or after date of enactment would be treated as a separate project. In the case of production from a project begun on or before the date of enactment, the percentage rate would be 18 percent rather than 27.5 percent.

With respect to production after the date of enactment, the bill would increase the net income limitation from 50 to 100 percent for incremental tertiary oil and gas to which the increased percentage depletion rate under the bill applies.

Also, the bill would remove from treatment as a minimum tax preference item excess depletion on incremental tertiary oil or gas

properties if the average annual removal price for the calendar year in which the taxable year begins is less than $30 (adjusted for inflation). This provision would be effective for production after date of enactment, and before January 1, 2010 (with respect to projects beginning before January 1, 2000).

S. 1565 (Senators Dole, Domenici, Boren, Nickles, Wallop, Gramm, and Baucus)

S. 1565 contains several provisions related to oil and gas percentage depletion for independent producers and royalty owners. First, the bill would repeal the anti-transfer limitation with respect to oil and gas property that is transferred after the date of enactment. It also would replace the 50-percent net income limitation with a 100-percent net income limitation. This latter provision would be effective for taxable years ending after date of enactment.

The following three provisions of S. 1565 would be applicable only with respect to marginal production of oil and gas. The bill defines marginal production as domestic crude oil or natural gas produced from a stripper well,[27] or domestic crude oil which is heavy oil. Each of these provisions would be effective for taxable years ending after the date of enactment.

First, with respect to such marginal production, percentage depletion would be permitted to be claimed without a 1,000 barrel per day limitation. Second, the bill would repeal the 65-percent taxable income limitation with respect to marginal production. Third, excess percentage depletion attributable to marginal production would not constitute an item of tax preference for the alternative minimum tax.

1989 Senate Finance Committee Provision

The 1989 budget reconciliation provisions as approved by the Senate Finance Committee (included in S. 1750 as reported by the Senate Budget Committee) would have repealed the 50-percent net income limitation for certain marginal production of domestic crude oil and natural gas. Production qualifying as marginal under the provision included oil or gas produced from a stripper well, and heavy oil. This provision was removed from the bill by Senate floor amendment.

Analysis

In general

Under percentage depletion, producers are allowed a deduction for a set percentage of gross income from a given property in each year (15 percent, in the case of independent oil and gas producers and royalty owners). Under present law, this allowance may reduce the net (i.e., taxable) income from a property by up to 50 percent in each year. Although nominally a form of cost recovery, percentage depletion has come to be seen as an implicit tax subsidy to the oil

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[27] The bill defines stripper well differently than does the 1979 Department of Energy regulations. Under the bill, a stripper well generally is any well that produced an average of 15-or-less barrels (or barrel equivalents) per day over any 6-month period (3 months in the case of a gas well) beginning after December 31, 1985.

and gas industry, in order to encourage production, because the total deductions with respect to a property may substantially exceed the actual costs invested in the property.[28] Since the Tax Reduction Act of 1975, this incentive has been limited to specified amounts of production by independent producers and royalty owners.

The various proposals regarding percentage depletion, by reducing the tax rate on oil and gas income, might favor the oil and gas industry over other sectors of the economy, such as agriculture and manufacturing. This might impact the long-run overall competitiveness of the U.S. economy. In addition, since oil and gas reserves are a finite resource, some may argue that encouraging production now would reduce domestic supplies in the future.

Percentage depletion rate

Under S. 234, the rate of percentage depletion for oil and gas would be increased from 15 percent to 30 percent as the average annual removal price of oil falls from $20 to $10 per barrel. The effect would be to increase the rate of percentage depletion when the income of domestic producers falls due to declining world oil prices. Other proposals (S. 41, and S. 828) also would increase the percentage depletion rate under specified circumstances.

An argument in favor of a variable rate of percentage depletion is that it would tend to stabilize the income of oil and gas producers. This provision is similar to certain agriculture stabilization programs which increase payments to farmers when farm income falls as a result of oversupply. However, such a policy could tend to destabilize the world petroleum market by encouraging domestic production when the world market is confronted by a glut (as evidenced by low prices). This could make it more difficult for the major oil-importing countries to coordinate energy policies.

Increasing the percentage depletion deduction for incremental tertiary oil and gas would provide a tax incentive to recover oil and gas which may not be recovered if the oil and gas were taxed under present law. However, to the extent that the recovery is not profitable from an economic viewpoint, lowering the tax on the profits may not provide relief.

Increasing the rate of percentage depletion would provide little or no benefit to many of the oil and gas producers hardest hit by the current relatively low petroleum prices: those producers with net operating losses. Additional depletion deductions have no immediate value to producers without income tax liability. Increasing the rate of percentage depletion on oil produced from existing wells would encourage more rapid depletion of these reservoirs, but might not encourage additional oil and gas exploration activity.

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[28] Percentage depletion was originally enacted in 1926 as a replacement for recovery based on "discovery values" of oil and gas properties, the determination of which had resulted in substantial litigation. The original statutory rate of 27.5 percent was reduced to 22 percent by the Tax Reform Act of 1969, and was subsequently repealed for integrated producers and phased down for others to 15 percent (for 1984 and thereafter) by the Tax Reduction Act of 1975. The 50-percent net income limitation dates from the industry-wide recession of the 1920s, during which depletion deductions (which were based on pre-recession values) frequently exceeded the income from oil and gas properties. The preference nature of the percentage depletion deduction is specifically recognized in the alternative minimum tax.

Percentage depletion on transferred property

Since 1975, the use of the percentage method for computing depletion deductions for oil and gas wells has been restricted to independent producers and royalty owners for limited amounts of crude oil and natural gas. At the time these restrictions were enacted, Congress recognized that taxpayers would attempt to maximize the amount of oil and gas eligible for percentage depletion by transferring ownership interests. Consequently, the 1975 Act specifies that the limitation on the amount of oil and gas eligible for percentage depletion is to be computed by aggregating the production of related parties. In addition, the 1975 Act generally disallows percentage depletion with respect to transfers of proven oil and gas property.

An argument for repeal of the anti-transfer rule is that by expanding the amount of oil and gas eligible for percentage depletion, the tax law would provide a more powerful incentive for production, and might prevent the abandonment of marginal wells that otherwise would be permanently closed. Oil and gas exploration activities also would be expected to increase as a result.

An argument against repeal of the anti-transfer rule is that integrated producers would be able to benefit indirectly from percentage depletion by selling productive oil and gas property to independents. The anti-transfer rule also prevents independent producers with less than 1,000 barrels per day of average production from buying proven reserves in order to use up their percentage depletion limitation. A substantial portion of the expected revenue loss attributable to this provision would result from the transfer of properties that are already developed, rather than the transfer of newly discovered oil and gas properties.

Net income limitation

The percentage depletion allowance can be viewed as a tax rate reduction. The 50-percent net income limitation acts to limit the rate reduction to 50 percent of the otherwise applicable income tax rate. For example, where production costs are zero, percentage depletion reduces the tax rate of a 28-percent bracket taxpayer (not subject to alternative minimum tax) to 23.8 percent (85 percent of 28 percent). As production costs rise, the tax rate is reduced from 85 percent of the otherwise applicable tax rate to 50 percent of such tax rate (for production costs at or above 70 percent of gross oil and gas income).[29]

An argument for repealing or modifying the 50-percent net income limitation is that it effectively eliminates the benefit of percentage depletion for producers who have little or no net income from oil and gas properties as a result of high exploration or production costs. Repeal of the net income limitation would allow per-

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[29] Consider a 28-percent tax bracket producer with $100 of gross income from oil and gas properties and zero production costs. In this case, net oil and gas income is $100 ($100 of gross income less zero production cost), the percentage depletion deduction is $15 (15 percent of $100), taxable income is $85 ($100 less $15), tax liability on oil and gas income is $23.80 (28 percent of $85), and the effective tax rate is 23.8 percent ($23.80 as a percent of $100 of net income). If production costs are $70, net oil and gas income is $30 ($100 of gross income less $70 of production cost), the percentage depletion deduction is $15 (15 percent of $100), taxable income is $15 ($30 less $15), tax liability on oil and gas income is $4.20 (28 percent of $15.00), and the effective rate is 14 percent ($4.20 as a percent of $30 of net income).

centage depletion deductions to be used against income from nonoil and gas activities, thus providing a potential benefit to producers without net oil and gas income. (Increasing the limitation to 100 percent would not benefit producers without net income from oil and gas properties.)

An additional argument for repealing or modifying the 50-percent limitation is that the alternative minimum tax and passive loss rules provided by the 1986 Act may be sufficient to prevent excessive use of percentage depletion deductions to shelter income unrelated to oil and gas activities.

Taxable income limitation

The 65-percent limitation acts to limit the sheltering of oil and gas income by unrelated tax losses. For a taxpayer subject to the 65-percent limitation, each dollar of tax loss from activities outside the oil and gas business reduces the taxpayer's percentage depletion deduction by 65 cents, resulting in a net shelter of 35 cents of oil and gas income.

An argument for repealing or modifying the 65-percent limitation is that the alternative minimum tax and passive loss rules provided by the 1986 Act may be sufficient to prevent excessive use of unrelated tax losses against oil and gas income. Another argument for repealing or modifying both the 65-percent and 50-percent limitations is that a producer subject to either limitation may have a tax incentive *not to* incur exploratory costs since such costs, in effect, only are partially deductible. This situation arises because each dollar of deductible expense (e.g., exploratory costs) reduces the percentage depletion deduction by 50 cents for a taxpayer at the 50-percent limit, and 65 cents for a taxpayer at the 65-percent limit. Increasing the limitations (for example to 100 percent) would, in effect, make exploratory costs 100-percent nondeductible for taxpayers subject to limitation.

Alternative minimum tax

S. 449, S. 828, and S. 1565 would remove excess depletion of various categories of oil and gas from items of tax preference for the alternative minimum tax. As an alternative measure, S. 234 would allow a taxpayer not able to use the benefits of percentage depletion by reason of being subject to the alternative minimum tax to carryforward excess percentage depletion to the next succeeding year.[30] The taxpayer then could use the deduction if it is not subject to the minimum tax in that succeeding year. This latter provision would allow a form of income averaging between minimum tax and regular tax years.

In enacting the various amendments to the alternative minimum tax rules in the 1986 Act, Congress attempted to make the U.S. tax system more equitable for all taxpayers. Congress concluded that the minimum tax should serve one overriding objective: to ensure that no taxpayer with substantial economic income could avoid significant tax liability by using exclusions, deductions and credits. Because excess percentage depletion represents depletion deduc-

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[30] The 1989 Act contains a provision that allows corporations a minimum tax credit in succeeding years for any minimum tax paid by reason of the preference for percentage depletion.

tions in excess of the taxpayer's basis in the depletable property (i.e., it represents deductions not actually paid by the taxpayer), Congress concluded that it should be considered an item of tax preference. It can be argued that to treat excess percentage depletion otherwise would be contrary to the purpose of the alternative minimum tax and would weaken the equity that the 1986 Act's amendments strived to create. To the contrary, others argue that the negative impact of the alternative minimum tax on domestic oil and gas exploration and production activity has been substantial, and that significant tax incentives are necessary in order to increase such activity.

3. Treatment of Surface Casing Costs

Present Law and Background

IDCs generally are limited to expenditures for items which do not have a salvage value (Treas. Reg. sec. 1.612-4(a)).

The Internal Revenue Service has ruled that, under present law, the cost of casing (including surface and production casing) and associated equipment must be capitalized and recovered through depreciation deductions, since the casing is deemed to have a salvage value.[31] Labor and other costs of installing the casing may be deducted as IDCs.

Proposals

S. 234 (Senator Boren)

Under S. 234, surface casing costs would be treated similar to IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

Under S. 449, surface casing costs would be treated similar to IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

Analysis

Surface casing generally is installed only after the producer has determined that production from the well is commercially viable. Allowing surface casing costs to be expensed rather than capitalized would tend to encourage development of proven properties. Thus, the proposal probably would increase oil and gas production, but only would indirectly affect exploration activity.

A general tax policy principle is that the costs of acquiring or producing an asset with a useful life or more than one year should be capitalized rather than expensed. Under present law, an exception from this principle is made in the case of IDCs. The proposal would expand this exception, increasing the preferential tax treatment of the oil and gas industry relative to other sectors of the economy.

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[31] *See*, Rev. Rul. 70-414, 1970-2 C.B. 132; Rev. Rul. 78-13, 1978-1 C.B. 63.

4. Treatment of Geological and Geophysical Costs

Present Law and Background

Under present law, geological and geophysical ("G&G") expenditures for the purpose of identifying and locating productive mineral properties must be capitalized and recovered through depletion deductions. These may include expenditures for reconnaissance surveys over a broad area, and more detailed surveys within an identified area of interest. G&G costs may be deducted as an ordinary business loss (sec. 165) if the entire area of a survey is abandoned as a potential source of mineral production.[32]

Proposals

S. 41 (Senator Nickles)

S. 41 would treat domestic (including U.S. possessions) G&G costs in the same manner as IDCs, effective for costs paid or incurred after the date of enactment.

S. 234 (Senator Boren)

Under S. 234, domestic (including U.S. possessions) G&G costs would be treated in the same manner as IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

Under S. 449, domestic G&G costs would be treated in the same manner as IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

Analysis

Under present law, G&G costs generally are recovered less rapidly than IDCs, since IDCs are not required to be capitalized and recovered through depletion deductions. The relatively less generous tax treatment of G&G costs relative to IDCs may be viewed as inequitable. Moreover, to the extent that G&G activity and exploratory drilling are substitutable methods for finding oil and gas reserves, the less favorable treatment of G&G costs relative to IDCs may bias exploration activity against G&G surveys. Providing taxpayers an option to expense G&G costs would reduce this tax bias against G&G activity.

An argument against expensing of G&G costs is that, under the uniform capitalization rules of the 1986 Act, taxpayers are required to capitalize most costs attributable to the production of inventory property and long-term construction contracts. Expensing of G&G costs would provide significantly more favorable tax accounting treatment to the oil and gas industry than other sectors of the economy.

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[32] *See,* Rev. Rul. 77-188, 1977-1 C.B. 76; Rev. Rul. 83-105, 1983-2 C.B. 51.

B. Energy-Related Tax Credits

1. Tax Credits for Exploration and Development

Present Law

No tax credit is provided for IDCs or similar expenses related to the exploration and development of domestic oil and gas under present law.

Administration Proposal

The Administration proposal would provide a 10-percent income tax credit for the first $10 million (per year per company) of IDCs attributable to exploratory drilling. A 5-percent credit would be allowed for the balance of the IDCs attributable to exploratory drilling. The credit could be applied against both the regular tax and the alternative minimum tax. However, the credit, in conjunction with all other credits and net operating loss carryovers, could not eliminate more that 80 percent of the tentative minimum tax in any year. Unused credits could be carried forward. The credit would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for a calendar year. This provision would be effective on January 1, 1991.

Other Proposals

S. 41 (Senator Nickles)

S. 41 would provide a 10-percent credit for the first $10 million of qualified investment and a 5-percent credit for any remaining qualified investment. Qualified investment means amounts paid or incurred for ascertaining the existence, location or quality of crude oil or natural gas and for developing reserves of crude oil or natural gas. The credit could offset both the regular tax and the alternative minimum tax. Excess credits could be carried back 3 years and forward 15 years. The credit would apply to expenditures paid or incurred in taxable years beginning after date of enactment, but would terminate after three years.

S. 234 (Senator Boren)

S. 234 would provide a 20-percent tax credit for the first $1 million of qualified investment and a 10-percent tax credit for the remaining qualified investment. Qualified investment means amounts paid or incurred for ascertaining the existence, location, extent, or quality of crude oil or natural gas, for developing reserves of crude oil or natural gas, and for performing secondary or tertiary recovery on domestic wells. The credit would offset both the regular tax and the alternative minimum tax. Excess credits would be carried back 7 years and forward 15 years. The credit would apply to expenditures paid or incurred in taxable years beginning after date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would provide a 20-percent tax credit for the taxpayer's qualified investment for a taxable year. Qualified investment means amounts paid or incurred (1) for G&G expenditures to ascertain the existence, location, extent, or quality of crude oil or natural gas, (2) for the purpose of developing and equipping crude oil and natural gas wells, and (3) for performing secondary or tertiary recovery on domestic wells. The credit would offset both the regular tax and the alternative minimum tax. Excess credits would be carried back 10 years and forward 15 years. The credit would apply to expenditures paid or incurred in taxable years beginning after date of enactment.

Analysis

An argument in favor of an oil and gas exploration tax credit is that the market may fail to generate a socially desirable level of investment in high risk and research-related activities. For example, the Code reflects this view by providing a 20-percent credit for increases in research and experimental expenditures.

In addition, some argue that the social cost of using oil exceeds its market price. The excess cost, or "premium", is attributable to the national security cost of oil use (including the cost of maintaining the strategic petroleum reserve), and the impact of increased U.S. petroleum consumption on the world petroleum market. Since the market price does not reflect the premium value of crude oil, according to this theory, domestic producers may fail to invest adequately in oil exploration. In this case, tax incentives for exploration and development may be desirable to achieve an adequate supply of petroleum.

Since a tax credit provides only a small benefit to taxpayers with little tax liability, it may be less efficient than a subsidy delivered through a direct spending program. In particular, independent oil producers may receive relatively less benefit from the credit than integrated producers since independent producers generate little or no income from refining or retailing operations. Also, independent producers benefit from full expensing of IDCs and the use of percentage depletion (although these benefits may be limited by the alternative minimum tax).

2. Tax Credits for Marginal Production, Etc.

Present Law

The tax laws do not differentiate between the taxation of income from production from marginal wells and other production. However, present law does provide a 20-percent credit for the amount of qualified research expenditures paid or incurred by a taxpayer during a taxable year that exceeds the average amount of the taxpayer's qualified research expenditures in the base period (generally the preceding three years). The credit is scheduled to expire after December 31, 1990.

Administration Proposal

The Administration proposal would provide a 10-percent tax credit for all capital expenditures on projects that represent the initial application of tertiary enhanced recovery techniques to a property. The credit could be applied against both the regular tax and the alternative minimum tax. However, the credit, in conjunction with all other credits and net operating loss carryovers, could not eliminate more than 80 percent of the tentative minimum tax in any year. Unused credits could be carried forward. The credit would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for a calendar year. This provision would be effective on January 1, 1991.

Other Proposals

S. 234 (Senator Boren)

S. 234 would provide a 10-percent credit for the lease operating expenses, depreciation expenses, depletion (not in excess of basis), overhead expenses, and severance taxes with respect to the production of domestic crude oil which is from a stripper well, heavy oil, or oil recovered through a tertiary process. The credit could offset both the regular tax and the alternative minimum tax. Unused credits could be carried back 7 years and forward 15 years. The credit would apply to oil produced in taxable years beginning after date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would provide a 20-percent credit for the lease operating expenses and severance taxes with respect to the production of domestic crude oil which is from a stripper well, heavy oil, oil recovered through a tertiary process, or harsh environment oil.[33] The credit could offset both the regular tax and the alternative minimum tax. Unused credits could be carried back 10 years and forward 15 years. The credit would apply to expenditures paid or incurred after the date of enactment in taxable years ending after date of enactment.

S. 828 (Senators Domenici, Boren, Dole, Nickles, Wallop, Garn, Bingaman, Johnston, McClure, and Gramm)

S. 828 would apply the credit for research and development separately to research relating to the discovery or improvement of tertiary recovery methods for oil and gas. The credit would be at a 10-percent rate. The provision would apply to amounts paid or incurred after the date of enactment and before January 1, 2010.

Analysis

Tax credits for marginal oil and gas production are intended to encourage the development or application of techniques for increasing the amount of oil that can be recovered economically out of a declining reserve. Since the continental United States is a mature

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[33] A credit at a reduced rate would be available for certain offshore wells.

oil province, many geologists now believe that improvements in enhanced oil recovery techniques offer much potential for increasing recoverable reserves.

3. Nonconventional Fuels Production Credit

Present Law

Present law provides a production credit equal to $3 per barrel of oil equivalent (adjusted for inflation since 1979) for qualified nonconventional fuels (sec. 29(a)). These fuels include oil or natural gas produced from unusual geologic formations and synthetic fuels derived from coal (including lignite). The amount of the production credit phases out as the unregulated annual average U.S. wellhead price per barrel of domestic crude oil rises above $23.50 (as adjusted for inflation since 1979).

In the case of natural gas produced from a tight formation, the credit applies only to gas which is price-controlled and which is entitled to at least 150 percent of the then applicable gas ceiling price established under section 103 of the Natural Gas Policy Act of 1978 (NGPA). In addition, the credit is inapplicable to any gas production from any property on which a well is located which is subject to an election to receive an incentive price under section 107(d) of the NGPA.

The production credit is available to qualified fuels that are (1) produced in a facility placed in service before January 1, 1991, or from a well drilled before January 1, 1991, and (2) sold before January 1, 2001.

Proposals

S. 234 (Senator Boren)

S. 234 would extend the January 1, 1991 placed in service termination date to January 1, 1996. The proposal also would delete the present-law limitations (discussed above) on the eligibility of gas from tight formations for the credit.

S. 343 (Senators Bingaman and Boren)

With respect to the nonconventional fuels credit, S. 343 would extend for 10 years the placed in service expiration date and the expiration date for sales of qualified fuels. Thus, the credit would apply with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 2001. Moreover, the credit would apply to sales of qualified fuels occurring before January 1, 2011.

The bill also would generally extend the credit to all gas produced from a tight formation.

S. 425 (Senator Domenici)

S. 425 generally would treat gas produced from a tight formation as qualifying for the nonconventional fuels production credit. Thus, the bill would delete the present-law requirements that the price of tight formation gas be regulated and that it be subject to a maximum incentive price level under the Natural Gas Policy Act of 1978. This provision would be effective for taxable years beginning

after December 31, 1984. If on the date of enactment, any refund or credit of tax resulting from this legislation would be barred by the statute of limitations, such refund or credit would, nevertheless, be made or allowed if a claim is filed within one year of the date or enactment.

The bill also would permit the credit to offset both the regular tax and the alternative minimum tax. This section of the bill would be effective for taxable years beginning after December 31, 1986.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would extend the January 1, 1991 placed in service termination date to January 1, 1998. The bill also would delete the present-law limitations (discussed above) on the eligibility of gas from tight formations for the credit.

S. 2025 (Senators Heinz, Moynihan, Durenberger, Danforth, Symms, Boren, Levin, McCain, Cochran, Burns, Akaka, Cohen, and Hollings)

S. 2025 would provide for the permanent extension of the nonconventional fuels production credit.

S. 2288 (Senators Domenici, Boren, Johnston, Dole, Bingaman, Ford, Simpson, Wallop, and Burns)

S. 2288 would extend the nonconventional fuels production credit for two years, making it applicable with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 1993. In addition, the bill would extend the credit to the production of gas from a tight formation if that gas is (1) produced from a well drilled after May 12, 1990, or (2) produced from a well drilled before May 12, 1990, but only if on that date gas produced from that well was gas that was regulated by the United States as to its price, and for which the maximum lawful price applicable under the Natural Gas Policy Act of 1978 is at least 150 percent of the then applicable price under section 103 of that Act. This latter provision would apply to gas produced after May 12, 1990.

Analysis

The alternative energy production credit was enacted in 1980 when oil prices had doubled within a period of one year. There was extensive interest in the United States to encourage development and production of alternative energy sources. Production of other fuels was to be encouraged by a production credit that was related to the price of oil, rate of inflation, and the BTU content of the fuel relative to that of petroleum.

Since 1981, the price of petroleum on world markets has fallen. Declining oil prices have squeezed the ability of alternative fuels to compete with oil because the costs of producing alternative fuels profitably has been stymied.

On the one hand, it may be argued that it is undesirable to continue the production credit in view of the present noncompetitive economic situation and the prospect that alternative fuels produc-

tion will need to be subsidized for long periods of time. On the other hand, the credit may be viewed as an investment in research and development for long-term future energy needs. If successful, these could yield significant future benefits.

4. Business Energy Credits

Present Law

A 15-percent energy credit is currently allowed for ocean thermal property. In addition, a 10-percent energy credit is currently allowed for solar energy property and geothermal property. Following the 1986 Act, only the business energy tax credits for the above three categories, plus a credit for certain investments in biomass energy property remained in effect. Although retained in the tax law, the 1986 Act reduced the credit percentage for most of these credits, and provided for the expiration of each of these credits by or before the end of 1988. The 1988 Act extended for one year (through 1989) the credits for solar energy, geothermal energy, and ocean thermal property. Moreover, the 1989 Act included a nine-month extension of these three credits. Each of the remaining business energy credits is currently scheduled to expire on September 30, 1990.

Proposals

S. 914 (Senator Matsunaga)

S. 914 would extend through December 31, 1994, the current business energy credits for solar energy property, geothermal property, and ocean thermal property.

S. 2025 (Senators Heinz, Moynihan, Durenberger, Danforth, Symms, Boren, Levin, McCain, Cochran, Burns, Akaka, Cohen, Hollings)

S. 2025 would provide for the permanent extension of various tax provisions that are currently scheduled to expire. Among these, the bill would extend permanently the current business energy credits for ocean thermal property, solar energy property, and geothermal property.

Analysis

The issues with respect to business renewable energy tax credits generally are (1) whether the credits have been available for a sufficiently long period of time to encourage production and sales at efficient, self-sustaining levels, and (2) if such production levels have not been reached, whether those levels will be attained solely because a tax credit is available.

5. Alcohol Fuels Credit and Related Provisions

Present Law

Alcohol fuels credit

An income tax credit is provided for alcohol used in certain mixtures of alcohol and gasoline (e.g., gasohol), diesel fuel, or any other liquid fuel which is suitable for use in an internal combustion

engine if the mixture is sold by the producer in a trade or business for use as a fuel or is so used by the producer (sec. 40(b)(1)). The credit also is permitted for alcohol (e.g., qualified methanol fuel) which is not in a mixture with gasoline, diesel, or other liquid fuel which is suitable for use in an internal combustion engine, provided that the alcohol is used by the taxpayer as a fuel in a trade or business or is sold by the taxpayer at retail to a person and placed in the fuel tank of the purchaser's vehicle (sec. 40(b)(2)). The credit is equal to 60 cents for each gallon of alcohol used as fuel. The credit is scheduled to expire after December 31, 1992.

Excise taxes

Excise taxes on gasoline, diesel fuel, special motor fuels, trucks and truck trailers, and truck tires make up the sources of tax revenue for the Highway Trust Fund (sec. 9503). The Highway Trust Fund taxes are scheduled to expire after September 30, 1993. Through that expiration date, an excise tax of 9 cents per gallon generally is imposed upon gasoline (sec. 4081), and an excise tax of 15 cents per gallon generally is imposed upon diesel fuel used in diesel-powered highway vehicles (secs. 4041(a)(1) and 4091). Also, an excise tax of 9 cents per gallon generally is imposed on certain special motor fuels (e.g., benzol, benzene, naphtha, and liquefied petroleum gas) used as fuel in a motor vehicle or motorboat (sec. 4041(a)(2)).[34]

Special reduced excise tax rates are applicable to certain fuel mixtures. Gasohol (i.e., any mixture of gasoline containing at least 10 percent alcohol) is subject to a reduced excise tax of 3⅓ cents per gallon, rather than the general rate imposed upon gasoline of 9 cents per gallon (sec. 4081(c)). Diesohol (i.e., any mixture of diesel fuel containing at least 10 percent alcohol) is subject to a reduced excise tax of 9 cents per gallon, rather than the general rate imposed upon diesel fuel of 15 cents per gallon (secs. 4091(c) and 4041(k)(1)(A)). Methanol and ethanol fuels (i.e., any liquid at least 85 percent of which consists of methanol, ethanol, or other alcohol produced from a substance other than petroleum or natural gas) is subject to a reduced excise tax of 3 cents per gallon (sec. 4041(b)(2)). An excise tax rate of 3 cents per gallon also applies to special motor fuels otherwise subject to tax under section 4041(a)(2) (e.g., benzol, benzene, naphtha, and liquefied petroleum gas) if the fuel contains at least 10 percent alcohol (sec. 4041(k)(1)(B)). The excise tax rate is 4½ cents per gallon in the case of any liquid at least 85 percent of which consists of methanol, ethanol, or other alcohol produced from natural gas (sec. 4041(m)).

Analysis

The main issue involving the alcohol fuels credit and exemption is whether these provisions should be allowed to expire as currently scheduled, or whether they should be extended (and if so, for how long). The excise tax exemption and the alcohol fuels credit were enacted to encourage conservation of petroleum by providing

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[34] The Code provides for various nonhighway use exemptions (generally via refunds or credits) from the excise taxes imposed on gasoline, diesel fuel, and special motor fuels. *See, e.g.*, secs. 4093, 6416, 6420, 6421, and 6427.

an incentive for production of gasohol mixtures which would reduce the amount of petroleum used in producing gasoline and stimulate the production of usable fuels from renewable sources. In an environment characterized by limits on the exploitation of natural resources, the substitution of ethanol produced from renewable plant matter for non-renewable petroleum products may be socially desirable. Tax subsidies for the renewable fuels industries are intended to increase reliance on renewable resources.

National security concerns may be addressed by increasing U.S. self-sufficiency in energy production. To the extent renewable sources of fuel grown domestically substitute for imported petroleum products, the goal of U.S. energy independence is furthered. National security also was a major policy concern when the alcohol fuel subsidies were enacted. The experience during the 1970s of the OPEC oil boycott of the U.S. and the extremely large price increases for petroleum threatened the ability of the U.S. economy to grow at an acceptable pace.

Use of ethanol in a gasohol mixture has been increasing steadily, but such mixtures still account for a modest proportion of gasoline consumption. Gasohol prices at the pump indicate that gasohol may not be competitive with gasoline without the subsidy in the form of the excise tax exemption or the alcohol fuels tax credit.

Support for the ethanol subsidies also is based on the claim that ethanol production leads to increased income for farmers who produce corn (which is the primary commodity used in producing ethanol) and has favorable effects on the farm price support program. Some doubt about the benefits of the ethanol program for the overall farm programs has been expressed by several observers.[35]

In addition, it has been raised by some that the alcohol fuels credit operates in a relatively inefficient manner. It has been argued that methanol could be utilized and is an easily obtainable substitute. Because methanol is less costly to produce, it might not require a government subsidy. Moreover, methanol also would be an environmentally beneficial substitute, it has been contended, since it is a relatively clean-burning fuel.

Some experts have questioned whether the alcohol fuels subsidies provided by the Code have a significant impact on the environment. Certain gasohol mixtures reduce automobile exhaust emissions of oxides of nitrogen, hydrocarbons, and particulates because 10 percent less gasoline is in the fuel mixture, but those benefits are offset by increases of more volatile emissions, e.g., ozone. Some contend that, on balance, the ambient air tends to remain about as polluted as it was without the use of these additives but with a different mixture of pollutants. [36]

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[35] *See, e.g.,* U.S. Department of Agriculture, *Ethanol: Economic and Policy Tradeoffs*, January 1988.

[36] Library of Congress, Congressional Research Service, "Emissions Impact of Oxygenated (Alcohol/Gasoline) Fuels," (CRS Report 87-436 S), May 20, 1987.

C. Other Energy-Related Provisions

1. Statute of Limitations for Certain Underpayments of Tax

Present Law

Except as provided in regulations, the crude oil windfall profit tax, prior to its repeal, [37] was withheld by the first purchaser of the oil from the price paid for the oil. The producer generally was required to file a return (Form 720) only if its windfall profit tax liability exceeded the amount of tax withheld during the calendar year. When required, Form 720 must be filed not later than May 31 of the next succeeding calendar year.[38]

If a producer was not required to file Form 720, the statute of limitations for assessment (or refund) of windfall profit tax runs three years from the due date of the producer's income tax return for the taxable year in which the removal year ends. If a Form 720 was filed, the limitation period runs for three years from the due date of that form.

In Rev. Rul. 85-37, 1985-1 C.B. 362, the IRS took the position that, if Form 720 was required to be filed (e.g., because of an underwithholding of windfall profit tax), but was not filed, the period for assessment is unlimited.

Proposal

S. 41 (Senator Nickles)

Under S. 41, for statute of limitations purposes, the producer would not be treated as having been required to file a windfall profit tax return if the amount of tax withheld by the first purchaser with respect to any oil was not less than the amount required to be withheld as shown on the return filed by the first purchaser. Thus, in such cases, a three-year statute of limitations would apply, measured from the due date of the producer's income tax return. This provision would be retroactive to the original effective date of the crude oil windfall profit tax.

Analysis

An unlimited assessment period generally is applied in cases where the IRS could not reasonably be expected to have notice of a taxpayer's failure to pay the correct amount of tax (e.g., in the case of failure to file a required return). Allowing a limited assessment period where no return was filed would be contrary to this policy. On the other hand, it may be argued that a producer who relied on the first purchaser's finding that no windfall profit tax was due should be treated in the same manner as a producer that was not required to file a return.

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[37] The tax was repealed by section 1941 of Public Law 100-418, effective for oil removed after August 23, 1988.

[38] The first purchaser of oil was required to file quarterly returns of withheld tax, including information necessary to facilitate coordination of withholding by the purchaser with the determination of tax on the producer of the oil.

2. Uniform Capitalization Rules

Present Law

The uniform capitalization rules generally require certain direct and indirect costs allocable to property to be included in inventory or capitalized in the basis of such property (sec. 263A). In general, the uniform capitalization rules apply to property produced by a taxpayer or acquired by a taxpayer for resale. The uniform capitalization rules do not apply to IDCs (sec. 263A(c)(3)).

Proposal

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 contains a provision that would extend the section 263A(c)(3) exemption from the uniform capitalization rules to any costs incurred relating to oil and gas exploration and development activities. Such costs would include, for example, lease acquisition and maintenance costs, G&G costs, and costs associated with drilling or completing oil and gas wells. This provision would be effective for costs paid or incurred after date of enactment.

Analysis

In 1986, Congress enacted the uniform capitalization rules. At that time, it was believed that the rules in effect prior to the 1986 Act were deficient in two respects. First, those rules allowed costs associated with the production, acquisition, or carrying of property to be deducted currently, rather than capitalized into the basis of the property and recovered when the property was sold or as it was used by the taxpayer. The result was a mismatching of expenses and the related income. Second, different capitalization rules could apply depending upon the nature of the property in question, possibly creating distortions in the allocation of economic resources and the manner in which certain economic activity was organized. Thus, Congress implemented a single, comprehensive set of rules to govern the capitalization of costs. The bill would exempt an entire industry from the uniform capitalization rules, thus possibly resurrecting some of the same problems and distortions with which Congress expressed concern in 1986.

3. Treatment of Offshore Dismantlement Costs

Present Law

As a general rule, the amount of any allowable deduction or credit is to be taken for the taxable year which is the proper taxable year under the taxpayer's method of accounting used in computing taxable income. Expenses generally may be accrued with respect to a liability when the "all events test" has been met (that is, when all the events have occurred which determine the existence of the liability and the amount of the liability can be determined with reasonable accuracy). However, a special rule provides that, except for certain recurring items, in determining whether an amount has been incurred with respect to any item (i.e., is deducti-

ble) during any taxable year, the all events test shall not be treated as met any earlier than when economic performance with respect to that item occurs (sec. 461(h)(1)).

The Code sets forth various principles to be followed in determining the time when economic performance occurs (sec. 461(h)(2)). One such principle deals with services and property provided to a taxpayer. In the case of services provided to a taxpayer, economic performance generally occurs when those services are so provided; for property provided to a taxpayer, economic performance generally occurs when that property is so provided; and if property is used by a taxpayer, it generally occurs as the taxpayer uses the property. A second principle involves services and property provided by a taxpayer. Under this principle, economic performance generally occurs when the taxpayer provides the property or services. The Code also specifies principles to be followed with respect to workers compensation and tort liabilities of the taxpayer, plus it provides authority to the Secretary of the Treasury to prescribe regulations which set forth economic performance rules for other items, and which provide exceptions to the principles discussed above.

Proposal

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 contains a provision that would provide a special rule for determining the time that economic performance takes place with respect to a liability for removal of an offshore oil and gas production facility. Under this special rule, economic performance would be deemed to occur while the facility is in use. Thus, the proposal would permit an accrual basis taxpayer to deduct costs related to the dismantlement of an offshore production facility prior to the time that such dismantlement commences.

Analysis

Advocates of this proposal may argue that if the taxpayer is contractually bound to dismantle its production facility, then the costs of dismantlement are related to, and should be allowable as a deduction against, the income generated from the operation of the facility. Once dismantlement begins, however, there may be no significant income generated by the facility against which the dismantlement costs may be deducted. Moreover, the rules permitting the carryback of net operating losses (as they relate, for example, to the alternative minimum tax) may not provide complete assurance that the taxpayer will get full utilization of the tax deduction for its dismantlement costs.

By contrast, others may argue that taxpayers should not be permitted to deduct expenses until the expenses are economically incurred. The allowance of a deduction for an expense to be paid in the future overstates the actual cost of the expense to the extent that the time value of money is not taken into consideration. That is, the deduction is overstated to the extent that the amount deducted exceeds the present value of the expense. The longer the

period of time between deduction and the actual payment of the expense, the greater is the overstatement.

Except for liabilities for certain recurring items, economic performance with respect to which occurs within a brief period after the close of the taxable year, taxpayers in all industries are precluded from claiming deductions for items with respect to which economic performance does not occur during the taxable year. If the proposal were enacted, taxpayers engaged in offshore exploration could be placed at a significant advantage vis-a-vis other taxpayers. Moreover, once an exception such as the one contemplated by the proposal is enacted, one might expect that other similar proposals designed to lessen the impact of the economic performance rules on other industries or groups of taxpayers may arise.

4. Revenue Ruling 77-176

Present Law

Under present law, the receipt of cash or other property in exchange for the performance of services is includible in the income of the person performing the services (secs. 61 and 83). In addition, a person who pays compensation in property other than cash recognizes gain or loss on the transfer of the property (sec. 1001).

The Internal Revenue Service has taken the position that when a driller, equipment dealer, or investor contributes materials and services in connection with the development of an oil and gas property in exchange for an economic interest in such property, the receipt of the economic interest does not result in the realization of income.[39] The contributors are viewed as not performing services for compensation, but rather as acquiring a capital interest through undertaking to make a contribution to the pool of capital.

In Revenue Ruling 77-176,[40] the IRS ruled that where the driller received a working or operating interest in the drill site as well as a separate working or operating interest in the tract exclusive of the drill site, the pool-of-capital doctrine set forth in GCM 22730 applies only to the interest acquired in the drill site itself, since the drill site is a separate property within the meaning of section 614. The owner of the lease is treated as having sold a portion of its interest in the tract exclusive of the drill site and as having paid the driller compensation in an amount equal to the value of that interest. The driller is treated as having received compensation in an amount equal to the value of the tract exclusive of the drill site. The IRS applied this ruling on a prospective basis.

Proposal

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

Under S. 449, the holding in Revenue Ruling 77-176 (and in any other regulation, ruling, or decision reaching the same (or a similar) result) would be reversed, and the law would be applied with-

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[39] GCM 22730, 1941-1 C.B. 214.
[40] 1977-1 C.B. 77.

out regard to that ruling. This provision would be effective on the date of enactment.

Analysis

Some may contend that Revenue Ruling 77-176 reversed a long standing IRS position regarding the exchange of oil and gas property for services. They may argue that by requiring the service performer to recognize income in such a case, the ruling discourages the use of joint arrangements to explore for oil and gas within a geologic prospect. Should that ruling be reversed, it is possible that domestic exploration and production activities would increase, as more mineral sharing arrangements would be utilized.

Others may argue that, consistent with general U.S. income tax principles, taxable income should be recognized on any receipt of property in exchange for the performance of services, and that no special exception should be made for the oil and gas (or any other) industry. To the extent that a service provider is permitted only in limited circumstances to defer income recognition with respect to property received, that person may be placed in a significantly advantageous position when compared to other service providers who receive partnership interests or other property in exchange for the services that they render.

5. Oil Import Fee

Present Law

Superfund and Oil Spill Fund taxes on petroleum

An excise tax of 9.7 cents per barrel of crude oil and imported petroleum products is imposed on the receipt of crude oil at a U.S. refinery, the import of petroleum products and, if the tax has not already been paid, on the use or export of domestically produced crude oil. Revenues from this tax, and certain other taxes, are deposited in the Hazardous Substance Superfund ("Superfund"). An additional excise tax of 5 cents per barrel is imposed on the same products, and revenues from this tax are deposited in the Oil Spill Liability Trust Fund ("Oil Spill Fund").

Petroleum products which are subject to tax upon import include crude oil, crude oil condensate, natural and refined gasoline, refined and residual oil, and any other hydrocarbon product derived from crude oil or natural gasoline which enters the United States in liquid form.

The Superfund and Oil Spill Fund excise taxes generally are scheduled to expire after December 31, 1991. The taxes will terminate earlier if cumulative Superfund tax receipts during the reauthorization period exceed $6.65 billion, and under certain other conditions.

Tariff on imported petroleum

Tariffs are imposed on various categories of articles that are imported into the customs territory of the United States. The tariffs generally are imposed at a uniform rate on imports from most noncommunist countries, with separate, higher rates imposed on imports from certain communist nations. Preferential treatment ap-

plies to certain imports from developing countries, specified Caribbean basin nations, and Israel. Imports from U.S. insular possessions, where the imported product is not comprised primarily of foreign materials, may be made duty-free.

Tariffs are imposed pursuant to the Tariff Act of 1930, and generally are subject to limitations imposed by the General Agreement on Tariffs and Trade (GATT). An import fee in excess of the GATT level generally is in violation of trade agreements and would subject the country imposing such a tariff to sanctions. However, under an exemption from the GATT, a tariff imposed on national security grounds is not a violation of trade agreements.

Currently, a tariff of 0.125 cent per gallon (5.25 cents per barrel) is imposed on crude petroleum, shale oil, and distillate and residual fuel oils derived from petroleum, with low density (under 25 degrees A.P.I.). For substances with higher densities (testing 25 degrees A.P.I. or more), the tariff is 0.25 cent per gallon.[41] Natural gas, together with methane, ethane, propane, butane, and mixtures thereof may be imported tariff-free. Under the recently negotiated Free Trade agreement with Canada, Canadian petroleum products will (after a phase-in period) be admitted tariff-free.

Import fee authority

Under the Trade Expansion Act of 1962, the President can impose oil import fees or import quotas if it is found that imports threaten the nation's security. Congress may roll back such fees by passing a joint resolution of disapproval; however, this resolution can be vetoed by the President, in which case the fees imposed would continue in effect unless the President's veto is overridden by a two-thirds vote of both Houses of Congress. These procedures for Congressional vetoes and overrides were specified by the Crude Oil Windfall Profit Tax Act of 1980.

Proposals

S. 42 (Senator Nickles)

S. 42 would impose an excise tax on crude oil or any other refined petroleum product that is imported into the United States on or after date of enactment. With respect to crude oil, the rate of the tax would be the excess (if any) of $18 over the price per barrel as established by the Secretary of the Treasury.[42] For other refined petroleum products, the excise tax rate would be equal to $3 plus the tax rate determined for crude oil. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export.

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[41] Imports from certain communist countries are subject to a 0.5-cent-per-gallon tariff, regardless of density. A 1.25-cents-per-gallon tariff (2.5 cents, for certain communist countries) also is imposed on certain motor fuels and a 0.25-cent-per-gallon tariff (0.5 cent, for certain communist countries) is imposed on petroleum-derived kerosene and naphthas (except motor fuels).

[42] This price, which is to be determined on a weekly basis under the bill, is the weighted average international price of a barrel of crude oil for the preceding four weeks.

S. 161 (Senators Boren and Kassebaum)

S. 161 would impose an excise tax on any petroleum product that is imported into the United States if the average international price of crude oil for any 4-week period is less than $18, and the product is entered into the United States for use, consumption, or warehousing during the week following such 4-week period. The rate of the tax would be the excess of $18 over the average international price per barrel of crude oil for the preceding 4-week period. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export. The bill would be effective with respect to sales of imported petroleum products in calendar quarters beginning more than 30 days after date of enactment.

S. 850 (Senators Johnston and Bingaman)

The bill would impose an excise tax on any crude oil, refined petroleum product, or petrochemical feedstock or derivative that is imported into the United States on or after date of enactment. With respect to crude oil, the rate of the tax would be the excess (if any) of $24 per barrel over the most recently published average price per barrel of internationally traded oil. For refined petroleum products and petrochemical feedstocks or derivatives, the excise tax rate would be equal to the excess (if any) of $26.50 per barrel (or barrel equivalent) over the most recently published average price per barrel of internationally traded oil.

Analysis

Some may argue that an increase in imported oil prices caused by an import tax or fee would encourage energy conservation and domestic exploration and production. Moreover, such a tax might lessen the United States' reliance on imported petroleum products and discourage the abandonment of marginal wells. Such a tax might also lessen environmental pollution to the extent that reduced petroleum consumption induced by the increased tax or fee would not be simply shifted to consumption of other fossil fuels (e.g., if increased conservation resulted from the increased tax). This could have a beneficial impact on the "greenhouse effect" if the amount of carbon dioxide released into the atmosphere were correspondingly reduced.

Proponents of an import tax might also contend that such a tax would result in an increased price for domestic oil, since domestic oil competes directly with imported oil. This effect could improve the financial health of domestic oil producers who have suffered from the decline in world oil prices occurring over the past several years.

On the other hand, a tax or fee on imported petroleum would likely increase the costs of domestic manufacturers and decrease their ability to compete against foreign producers in both the domestic and world markets. Statutory devices designed to relieve U.S. exported goods from the impact of the tax may be difficult to administer. It might also be argued that a tax or fee on imported petroleum reflected in higher prices would impose a relatively larger burden on low-income households as compared to high-

income households, since poorer households spend a larger portion of their disposable income on non-discretionary uses of petroleum products (e.g., transportation and home heating costs).

Further, the proposal would adversely affect Mexico, Canada, the United Kingdom, and other non-OPEC oil producers who jointly supplied nearly half of the petroleum imported into the United States in 1989.

Finally, in 1989 a number of Senators jointly sponsored Senate Resolution 64, which expressed opposition to the imposition of a fee on imported crude oil and refined petroleum products.[43] Specifically, the resolution expressed objection to the imposition of such a tax on the grounds that the fee would (1) directly increase the costs of production and manufacturing for industries using petroleum products, (2) impair the ability of industries to compete in international markets, (3) directly increase the costs to other users of petroleum products, including those dependent on oil and oil products to heat their homes (and those who use electricity generated from oil), and (4) be borne disproportionately by those industries and geographic regions most dependent on petroleum products.

[43] The Resolution was sponsored by Senator Pell. It was co-sponsored by Senators Chafee, Mitchell, Kennedy, Leahy, Rudman, Cohen, Heinz, Lautenberg, Matsunaga, Humphrey, Jeffords, Kerry, and Metzenbaum.

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